SECTION 5 – AREA OF REVIEW

5.1 Delineation of the Area of Review

The area of review (AoR) for the combination of the Illinois Industrial Carbon Capture and Sequestration (IL-ICCS) project and the Illinois Basin-Decatur Project (IBDP) has been delineated. This revised delineation is shown and described herein. This revision has been prompted by two significant events:

1. Improvements and calibrations to the Geologic and Reservoir Simulation models.
2. A forthcoming determination by the United States Environmental Protection Agency (EPA) to classify the St. Peter Sandstone as the lowermost underground source of drinking water (USDW). Previous AoR delineations were based on the lowermost USDW being within 200 feet from land surface in a water yielding stratum of the Pennsylvanian bedrock.

5.2 Method of Delineation

The delineation of the AoR is based on the *Maximum Extent of the Separate-phase Plume or Pressure-front (MESPOP)* methodology, as detailed in the relevant US EPA guidance document (USEPA, 2011). Information about the lowermost USDW and target injection zone obtained from the on-going efforts of the Illinois Basin-Decatur Project (IBDP) provided the input for the hydraulic head calculations specified in the guidance. Figure 5-1 illustrates the input values to these calculations and the graphical relationship between the hydraulic head in the lowermost USDW (considered to be the St. Peter Sandstone) and that of the target injection interval of the lower Mt. Simon Sandstone. The pressure front delineation was calculated using:

$$P_{i,f} = P_u \cdot \frac{\rho_i}{\rho_u} + \rho_i g \cdot (z_u - z_i)$$

The equation is further defined in Figure 5-1. The results of these calculations indicates that the pressure front in the injection zone ($P_{i,f}$) is delineated by a pressure of 22.68 MPa (3290 psi), or a change in pressure of 1.18 MPa (171 psi) above the initial reservoir pressure.

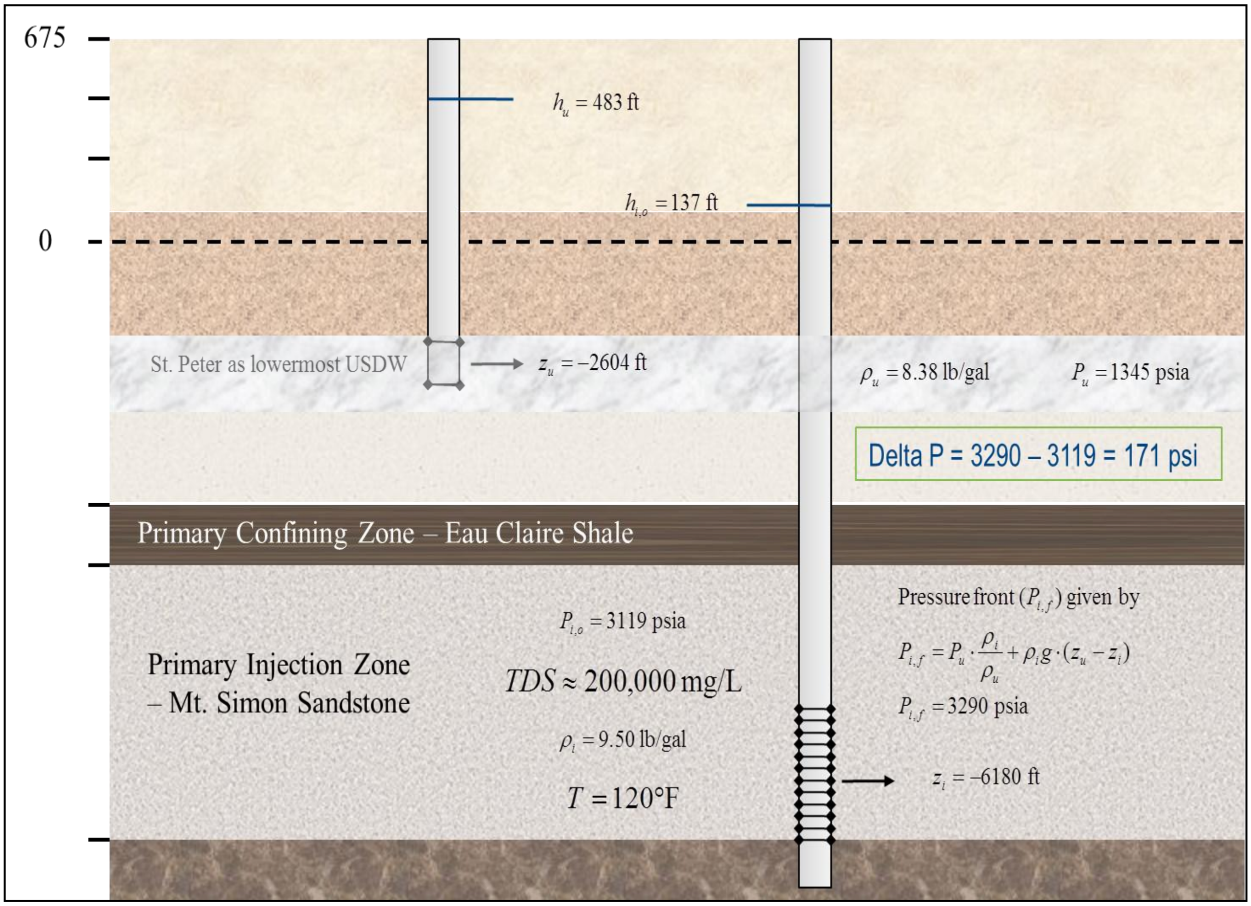


Figure 5-1: Illustration of pressure front delineation calculation based using the St. Peter Sandstone is as the lowermost USDW. The site specific data used to determine the MESPOP originated from the following: the St. Peter formation pressure was determined from a Drill Stem Test (DST) conducted in 2009 on CCS#1, the Mt. Simon formation pressure data came from (MDT*) modular formation dynamics tester data on CCS#1, and the fluid density data came from reservoir fluid samples taken from the Mt. Simon using Verification Well #1. All other required data inputs were correlated from site specific log data or came from historic regional geologic data.

Since the original permit application was made in July 2011, several changes and calibrations have been made to update the static geologic and dynamic reservoir models and are further described in Section 5.4.2. Using the updated models, a simulation was run for a 52 year period and Figure 5-2 shows the models predicted delineation of the AoR over a satellite image of the project site. As seen in this figure, the MESPOP grows to a maximum extent of approximately 9.4 square kilometers (3.6 square miles). The AoR is no longer exclusively defined by the pressure front as the model predicts that the extent of the carbon dioxide (CO_2) plume will extend outside of the pressure front boundary during most of the 52 year simulation period. When compared to the AoR predicted in the original permit application submitted in the July 2011 (shown in blue), the new AoR is significantly smaller. This is principally due to permeability changes that resulted from new data obtained from well core analysis and current IBDP injection well operating conditions. Additional details about the model input parameters and simulation results are discussed in Section 5.4 below.

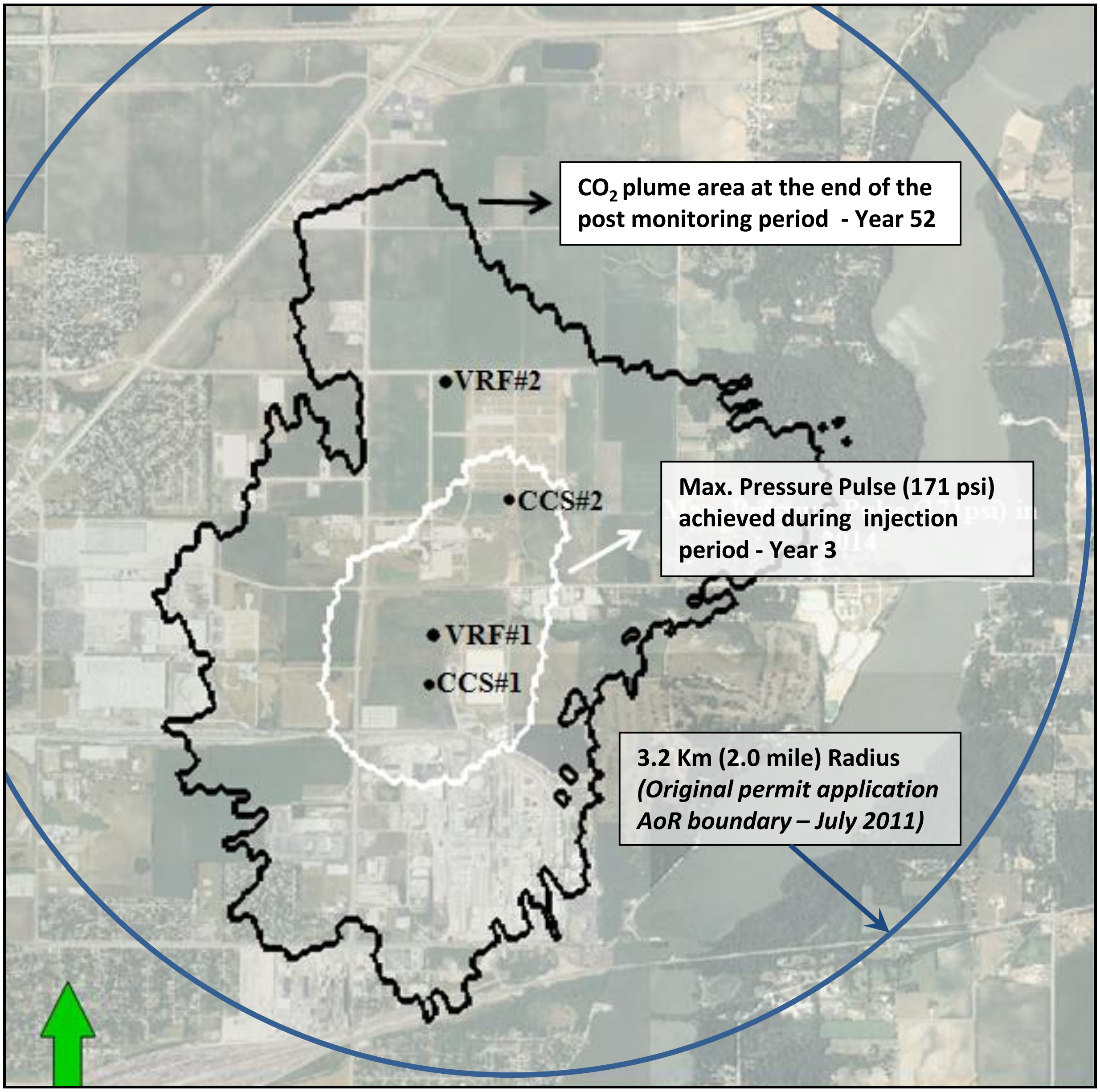


Figure 5-2: AoR delineation showing an overlay of the maximum extent of the plume and pressure front. The 171 psi pressure front is shown by the white line and is defined by the differential pressure needed to allow fluid from the injection zone to flow through a hypothetical open conduit into the overlying lowermost USDW (St. Peter Sandstone). The maximum extent of the pressure front, as determined by the latest modeling, occurs in 2014 (Year 3). The maximum predicted extent of the subsurface CO_2 plume (shown by the black line) is larger than the pressure front and therefore defines the delineation of the AoR. From the July 2011 permit application, the original delineation of the AoR is shown as a blue line.
Please note that VRF#1 = Verification Well #1 and VRF#2 = Verification Well #2.

5.3 Area of Review Map

The only existing wells within the AoR which currently penetrate the caprock (Eau Claire Formation) are the IBDP injection and verification wells, i.e. CCS#1 and Verification Well #1. CCS#1 and Verification Well #1 were constructed in 2009 and 2010 respectively and well construction records have been provided to USEPA. Both IBDP wells are operating under permit number UIC-012-ADM issued by the Illinois EPA.

A map and cross reference table showing the location of all well penetrations within a 3.2 km (2.0 mile) radius of the IL-ICCS site is provided in Appendix D. Please note that the radius of 2.0 miles is larger than the AoR delineation shown in Figure 5-2. Therefore Appendix D contains information for some wells that fall outside the new AoR.

5.4 Description of Anticipated Injection Fluid Movement during the Life of the Project

5.4.1 Simulation Software Description and General Assumptions

Schlumberger Carbon Services utilized ECLIPSE 300 (v2011.2) reservoir simulation software with the CO_2STORE module to estimate subsurface CO_2 plume movement and reservoir pressure behavior below the IL-ICCS site. ECLIPSE 300 is a compositional finite-difference solver that is commonly used to simulate hydrocarbon production and has various other applications including carbon capture and storage modeling. The CO2STORE module accounts for the thermodynamic interactions between three phases: an H_2O-rich phase (i.e. 'liquid'), a CO_2-rich phase (i.e. 'gas'), and a solid phase, which is limited to several common salt compounds (e.g. NaCl, $CaCl_2$, and $CaCO_3$). Mutual solubilities and physical properties (e.g. density, viscosity, enthalpy, and etc.) of the H_2O and CO_2 phases are calculated to match experimental results through a range of typical storage reservoir conditions, including temperature ranges between 12-100°C and pressures up to 60 MPa. Details of this method can be found in Spycher and Pruess (Spycher & Pruess, 2005). Additional assumptions governing the phase interactions throughout the simulations are as follows:

- The salt components may exist in both the liquid and solid phases.
- The CO_2-rich phase (i.e. 'gas') density is obtained by using the Redlich-Kwong equation of state. The model was accurately tuned and modified as further described below (Redlich & Kwong, 1949).
- The brine density is first approximated as pure water then corrected for salt and CO_2 concentration by using Ezrokhi's method (Zaytsev & Aseyev, 1992).
- The CO_2 gas viscosity is calculated per the methods described by Vesovic and Fenghour (Vesovic, Wakeham, Olchowy, Sengers, Watson, & Millat, 1990) and (Fenghour, Wakeham, & Vesovic, 1999).

The gas density was obtained using a modified Redlich-Kwong equation of state following a method developed by Spycher and Pruess, where the attraction parameter is made temperature dependent:

$$P = \left(\frac{RT_K}{V - b_{mix}}\right) - \left(\frac{a_{mix}}{T_K{}^{1/2} V(V + b_{mix})}\right)$$

where V is the molar volume, P is the pressure, T_K the temperature in Kelvin, R is the universal gas constant and a_{mix} and b_{mix} are the attraction and repulsion parameters.

The transition between liquid CO_2 and gaseous CO_2 can lead to rapid density changes of the gas phase, the simulator use a narrow transition interval between the liquid and gaseous density to represent the two phase CO_2 region.

Because the compression facility controls the CO_2 delivery temperature to the injection well between 80°F and 120°F, the temperature of the injectate will be comparable to the reservoir formation temperature within the injection interval, (Section 7.4.8). Therefore, the simulations were carried out based on isothermal operating conditions. With respect to time step selection, the software algorithm optimizes the time step duration based on specific convergence criteria designed to minimize numerical artifacts. For these simulations, time step size ranged from 8.64×10^1 to 8.64×10^5 seconds or 0.001 to 10 days. In all cases, the maximum solution change over a time step is monitored and compared with the specified target. Convergence is achieved once the model reaches the maximum tolerance "sufficiently small change" for temperature and pressure calculation results on successive interations. New time steps are chosen so that the predicted solution change is less than a specified target.

5.4.2 Site Specific Assumptions and Methodology

The 3D geologic model developed for the injection simulations is based on the interpretation of a diverse collection of geological, geophysical, and petrophysical data acquired throughout the construction of the IBDP wells (CCS#1 and Verification Well #1). Structurally, the model is also based on the interpretation of both two dimensional (2D) and three dimensional (3D) seismic survey data in conjunction with dipmeter log data acquired from the IBDP wells. Petrophysical and transport properties based on the interpreted well log data and the analysis of core samples recovered from the IBDP wells were then distributed throughout each layer in the geocellular model (Appendix K: ADM CCS #1 - Geophysical Log Descriptive Report). The original AoR delineation submitted to USEPA in July 2011 was developed using a 3D model with a homogeneous or layer cake distribution of petrophysical and transport properties that were primarily based on data from CCS#1. In August 2011, the processing of the 3D seismic dataset obtained for the IL-ICCS project was completed. Based on the interpretation of the new 3D seismic data and IBDP well core analysis, in October 2011, a revised geologic model was constructed which utilizes a geo-statistical distribution of petrophysical and transport properties. This new model became the basis for the newly revised reservoir simulation model used to determine the new AoR.

In November 2011, injection of CO_2 into CCS#1 began and as of May 2012, approximately 150,000 metric tons of CO_2 have been injected. Operational data from this project was used to calibrate the reservoir model being used for both the IBDP and IL-ICCS projects. Data obtained includes injection well bottom hole pressure (BHP), multi-zone pressure data from Verification Well #1, Spinner data, i.e. injection profile logs in CCS#1, and reservoir saturation tools (RST) from both IBDP wells. These datasets have provided additional information to allow calibration of various reservoir parameters including intrinsic permeabilities, relative permeabilities, wellbore skin, vertical to horizontal permeability ratios, and rock compressibility. These calibrations are allowing the model to be updated periodically to improve the accuracy between the model prediction versus the actual result.

Monitoring data used for pressure matching includes:

- Injection Rate
- Injection Bottom hole Pressure – real-time data collected from a down hole gauge in the injection well about 600 ft above the perforations
- Westbay*multilevel groundwater characterization and monitoring system pressures – real-time pressures located at specific zones in the verification well 1000 ft. north of injection well. Five out of ten zones used for model calibration
- Spinner Data-Flow partitioning between perforations – log run in injection well in March 2012
- RST Well Logs – CO_2 Saturations around CCS#1 and VRF#1 – logs run in March 2012

Reservoir simulation studies used ECLIPSE 300 (v2011.2) reservoir simulation software with the CO_2STORE module, which is primarily used to model CO_2 storage in saline formations. For the CO_2STORE option, three phases are considered; a CO_2 rich phase, an H_2O rich phase, and a solid phase.

The static geological model included the entire Mt. Simon Sandstone and the overlying seal (Eau Claire Formation) spanning a 40 × 40 mile area; and was represented with a 1298 × 1308 × 534 grid. Average cell size was 150 × 150 × 3.5 ft (i.e. x, y, z where z is vertical). Based on the previous models, it was concluded that the pressure pulse propagation within the 20 × 20 mile area was satisfactory for the purposes of the study. Hence, given the very detailed nature of the geological model, the reservoir model was built to cover an area of 20 × 20 mile and included the entire thickness of both reservoir and the seal rock. The geological model was downscaled to 50 ft (x and y dimensions) around the wellbore for better reservoir model resolution. In the far field region, cells were upscaled up to 1500 ft, laterally. Vertical resolution (z) of the geological model was maintained in the lower 700 ft of the reservoir where CO_2 was expected to remain. In the upper section of the model, the vertical dimension of the cells were increased up to 75 ft. The resulting cellular model was represented by a high resolution 143 × 143 × 148 unit grid locally refined around the injector.

The model's porosity within the injection interval ranges from 8 to 26%. The model's temperature and pressure gradients of approximately 1.8°C/100-m (1°F/100-ft) and 10.2 MPa/km (0.45 psi/ft) were based on in-situ measurements made after drilling the IBDP wells. The formation pressure gradient in the lower half of the Mt. Simon is slightly higher than a typical fresh water gradient due to the high salinity observed in this part of the reservoir, which ranges from 179,800 ppm to 228,000 ppm total dissolved solids (TDS) based on analysis of actual formation fluid samples recovered during the drilling of CCS #1 (Frommelt, 2010). Another governing parameter used in the reservoir simulation was the fracture pressure gradient of the lower Mt. Simon Sandstone. The fracture pressure gradient in the lower Mt. Simon was demonstrated via step rate test in CCS #1 to be 16.2 MPa/km (0.715 psi/ft) (refer to Section

2.4.3.3 for description). For the purposes of the reservoir simulations, the bottom hole injection pressure in CCS #1 was allowed to operate up to 80% of this gradient, whereas the bottom hole injection pressure in CCS #2 was allowed to operate up to 90% due to the higher injection rate. During the course of the simulation, CO_2 is injected into CCS #1 for two (2) years at 1,000 MT/day, followed by one (1) year of dual injection (1,000 MT/day into CCS #1 and 2,000 MT/day into CCS #2) followed by four (4) years of injection into CCS #2 at 3,000 MT/day with CCS #1 shut-in. Following the site's seven (7) year injection period, a 45 year post monitoring (shut-in) period was simulated in order to understand the long-term behavior of the CO_2 plume and the reservoir pressure within the injection zone. The injection of CO_2 was confined to the lower part of the Mt. Simon, just above the basal arkosic zone, since it is the most porous and permeable interval in the injection zone. In the case of CCS #1, the existing ('as-completed') perforated interval of 16.8 m (55 ft) was used in the simulation (Frommelt, 2010), whereas in the case of CCS #2, the planned well design having a perforated injection interval of 100 m (330 ft) was used in the simulation model.

The site model was calibrated using data obtained during the first four (4) months of the IBDP injection period. The IBDP injection rate was input into the simulation to calculate the bottom hole pressures and pressures at five different zones at the verification well. The simulated pressures compared to the observed pressures. Reservoir permeability and skin were the main parameters impacting the injection pressure calibration and were used as fitting parameters. Actual spinner data was used to set the fractions of the total injection between the two set of perforations in the injection well. These data along with the simulation allowed for fine tuning of the skin values at respective perforations together with the permeability to match injection bottom hole pressure (Figure 5-3).

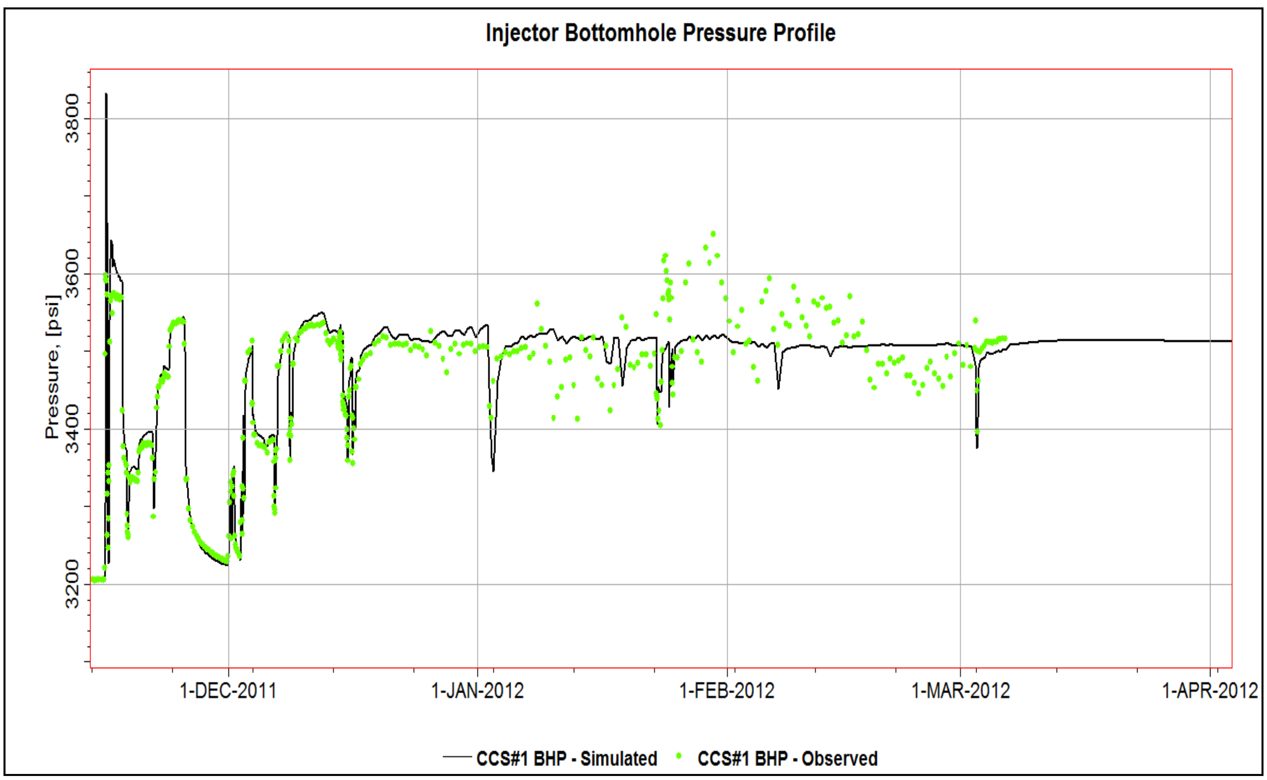


Figure 5-3: History Matched Injection Bottom Hole Pressure (BHP) for CCS#1.

Once the injection bottom hole pressure was calibrated, simulated pressures at five different zones at the verification well were fine-tuned calibrating the k_v/k_h ratio of the tight sections and compressibility of the reservoir rock (Figure 5-4).

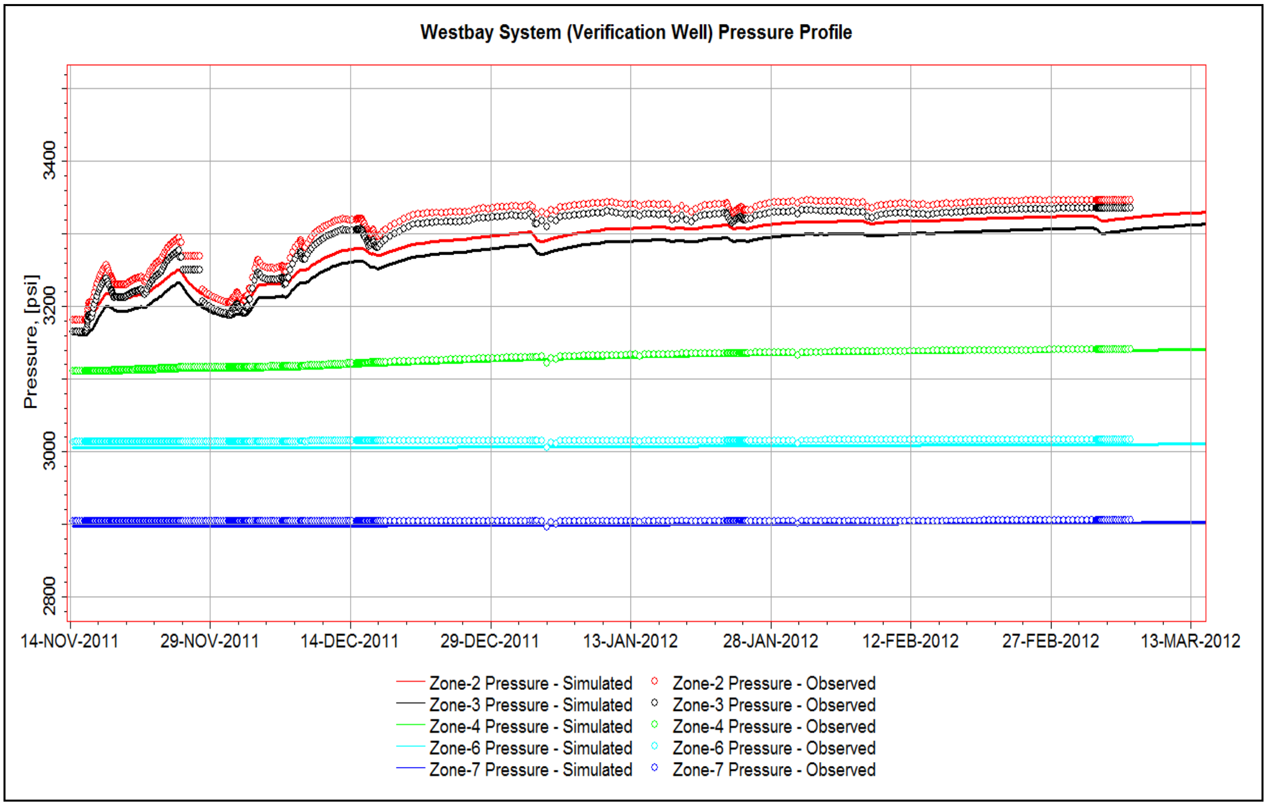


Figure 5-4: History Matched Pressures at Verification Well for CCS#1

RST Well Logs helped us estimate the location, saturation, and thickness of the CO_2 column around the injection and verification wells. This information helped us fine tune the end points of relative permeability curves which dominate the CO_2 and brine flow in the reservoir. Figure 5-5 shows relative permeability curves of the CO_2-brine system during drainage and imbibition with respect to brine saturation (S_w). Where: brine drainage (krw) represents the relative permeability of brine during drainage, brine imbibitions (krw) represents the relative permeability of brine during imbibition, CO_2 drainage (krg) represents the relative permeability of CO_2 during drainage, and CO_2 imbibition (krg) represents the relative permeability of CO_2 during imbibition. S_{wi} (irreducible water saturation) is approximately 60% as assumed in the reservoir simulation. Please note that drainage is defined as CO_2 replacing brine in the pores and imbibition is defined as brine replacing CO_2 in the pores.

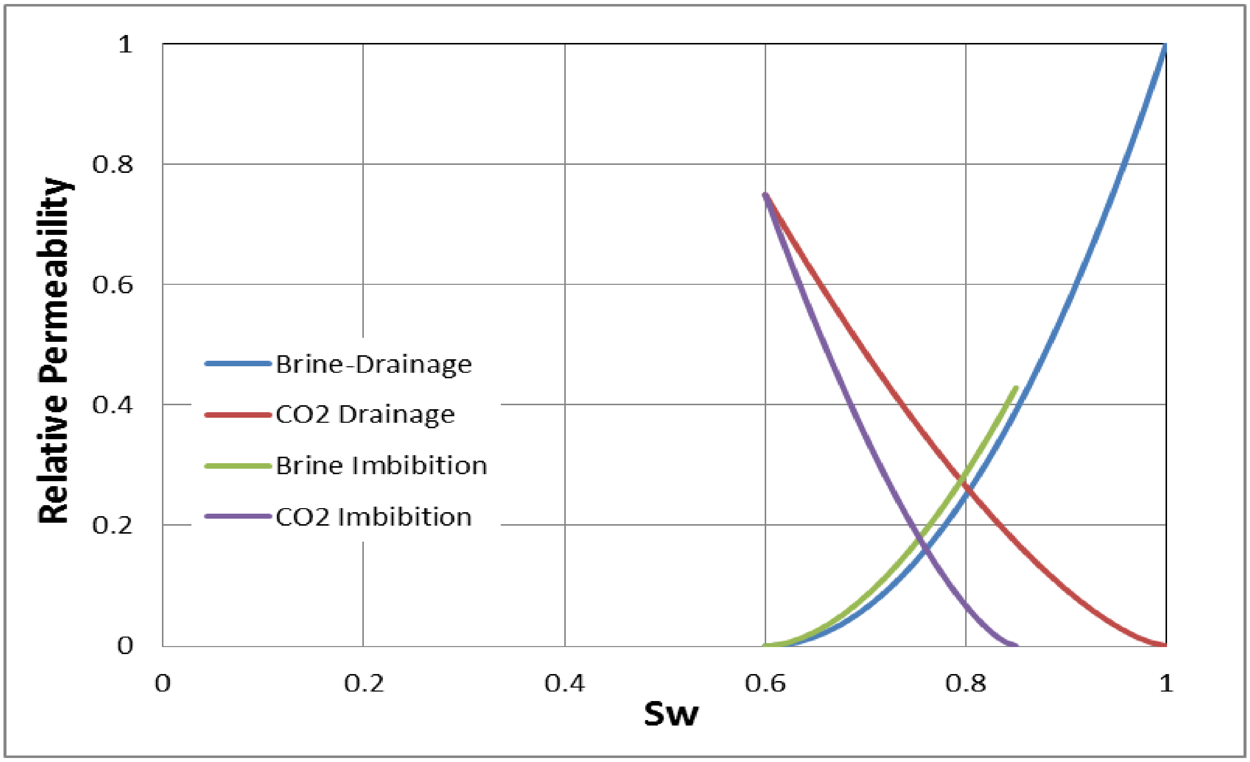


Figure 5-5: Calibrated Reservoir Unit Relative Permeability Curves

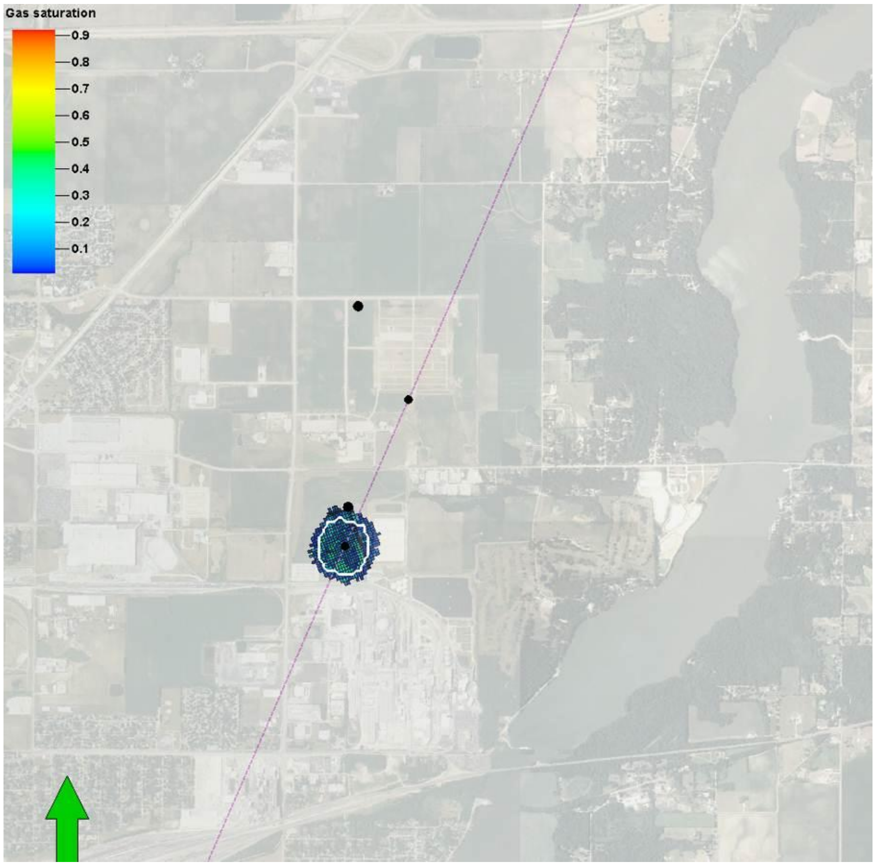
Using the calibrated model, a predictive simulation was run to evaluate plume development and pressure perturbation during the course of the injection. The injection schedule used for the purpose of the forward simulation can be seen in Table 5-1.

YEAR	IBDP (MT/D)	IBDP (MT/YR)	ICCS (MT/D)	ICCS (MT/YR)
1	1,000	333,333		
2	1,000	333,333		
3	1,000	333,333	2,000	730,000
4			3,000	1,000,000
5			3,000	1,000,000
6			3,000	1,000,000
7			3,000	1,000,000
Total		**1,000,000**		**4,750,000**

Table 5-1: Injection Schedule for IBDP (CCS#1) and IL-ICCS (CCS#2) Projects

5.4.3 *Simulation Results*

Based on simulation results, the CO_2 plume resulting from injection into CCS #2 will interact with the CCS #1 plume. Since the injection interval is near the base of the Mt. Simon, CO_2 flows upward from the injection interval due to its lower density compared to the native brine. As it rises, CO_2 saturation increases below the lower permeability intervals within the Mt. Simon. This pooling causes the CO_2 to spread laterally beneath these lower permeability strata which results in slow growth of the plume. It is these lower permeability strata within the Mt. Simon that limit the ultimate vertical migration through the injection zone, such that after five years of continuous injection through the CCS#2 well and 45 years of shut-in, the CO_2 remains well within the lower half of the Mt. Simon. Figures 5-6 through 5-14 depict map-view representations of the aggregate plume area at various times superimposed on a satellite image of the project area. A cross section view (along the plane intersecting both injection wells) is also included in each figure. Also depicted in these figures is the development of the 171 psi pressure front ($P_{i,f}$) boundary through simulated time. Figures 5-15 through 5-17 show the cross section views for years 30, 40, and 50 respectively. Finally, Figure 5-18 shows the outline of the CO_2 plume in year 2062 (Year 50) over the map-view CO_2 plume footprint in the year 2030 (Year 18). From this figure it can be seen that the plume growth during the 32 year period is minimal indicating the plume has become stable.



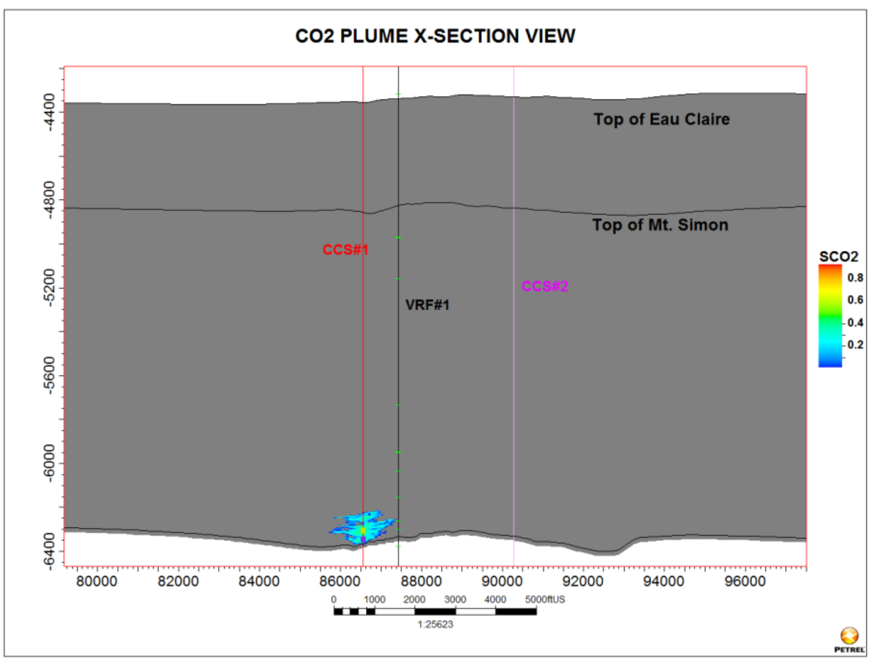
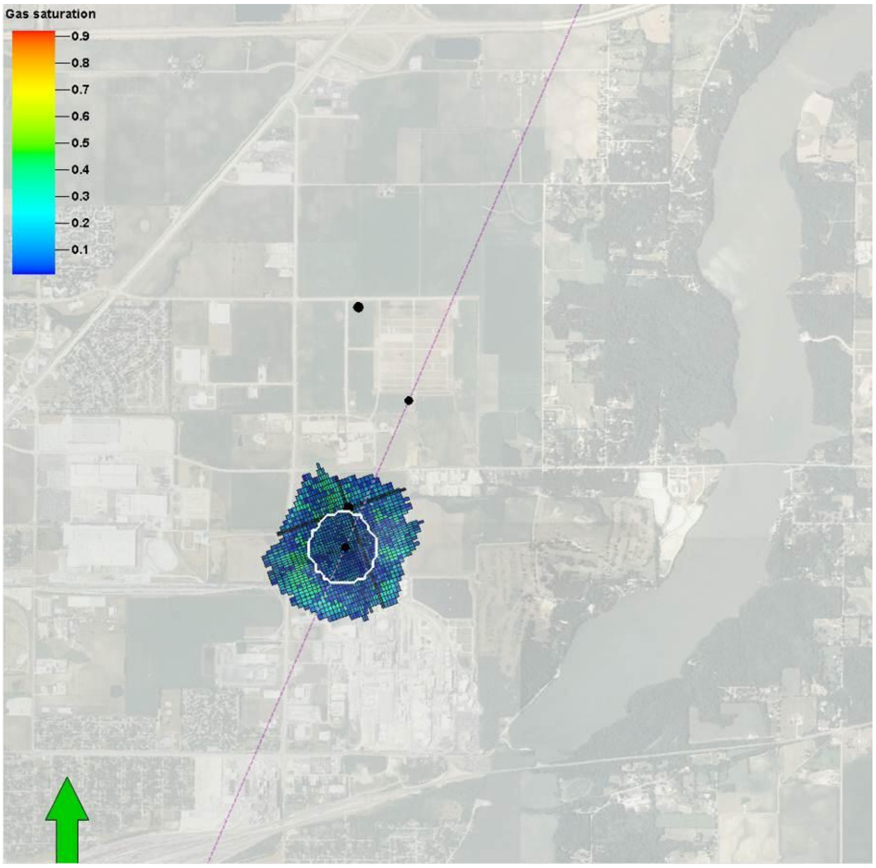


Figure 5-6: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints at the calibration point of March 2012 (Year 0.3). The outside edge of the 171 psi pressure front is depicted by the white circle. The plume extent is depicted by the green shading. CCS#1, VW#1, CCS#2, and VW#2 are depicted by the black dots and are located from south to north respectively.



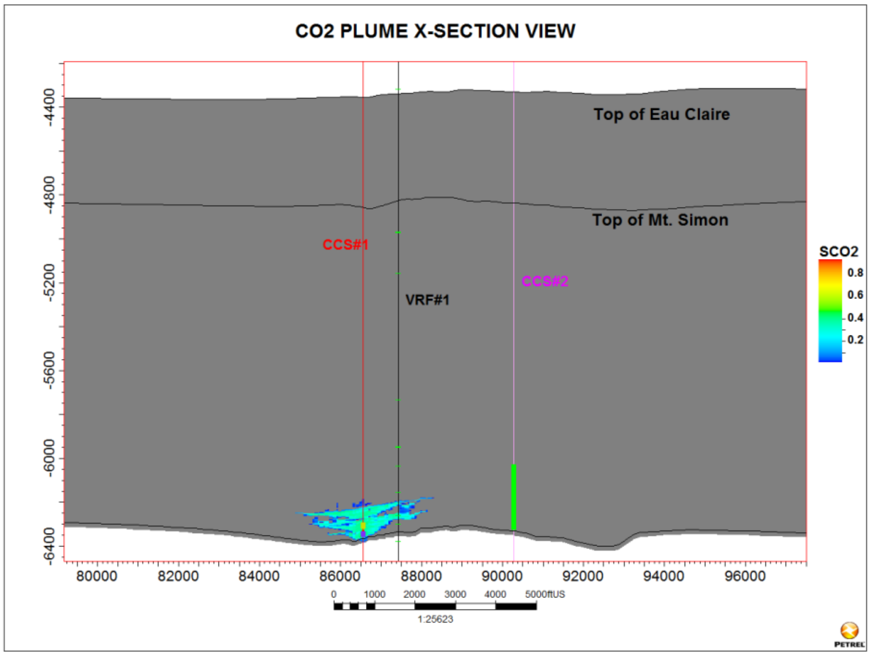
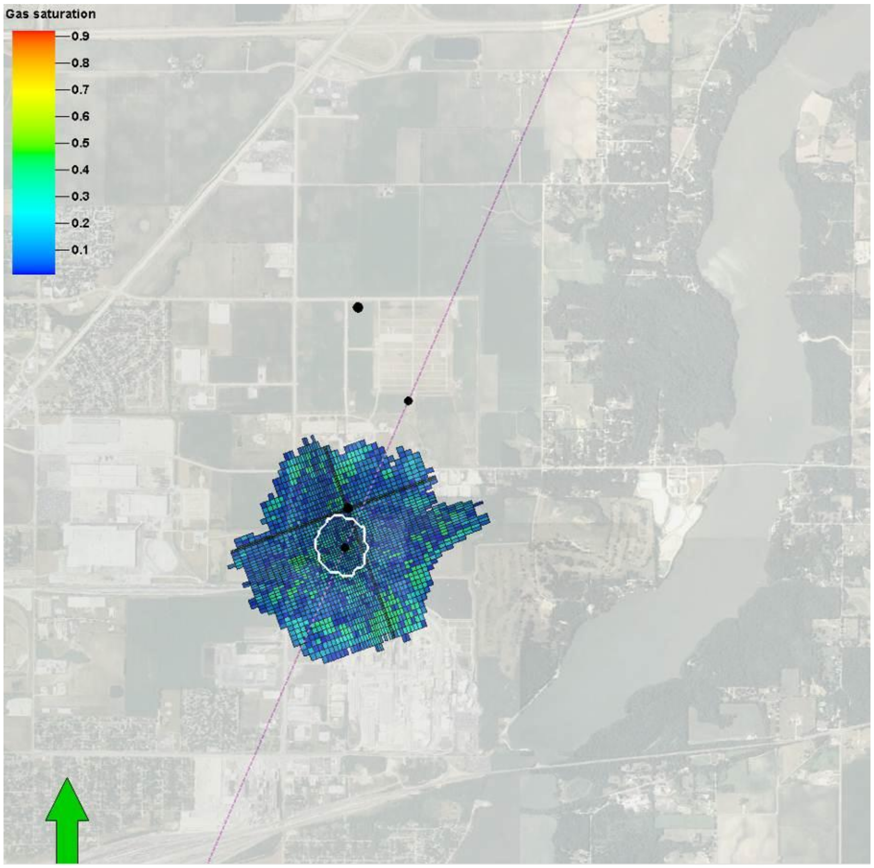


Figure 5-7: Map-view of and cross section views of the model predicted pressure front ($P_{i,f}$) and CO_2 plume footprints at the start of 2013 (Year 1). The green bar represents the designed perforation interval for CCS#2.



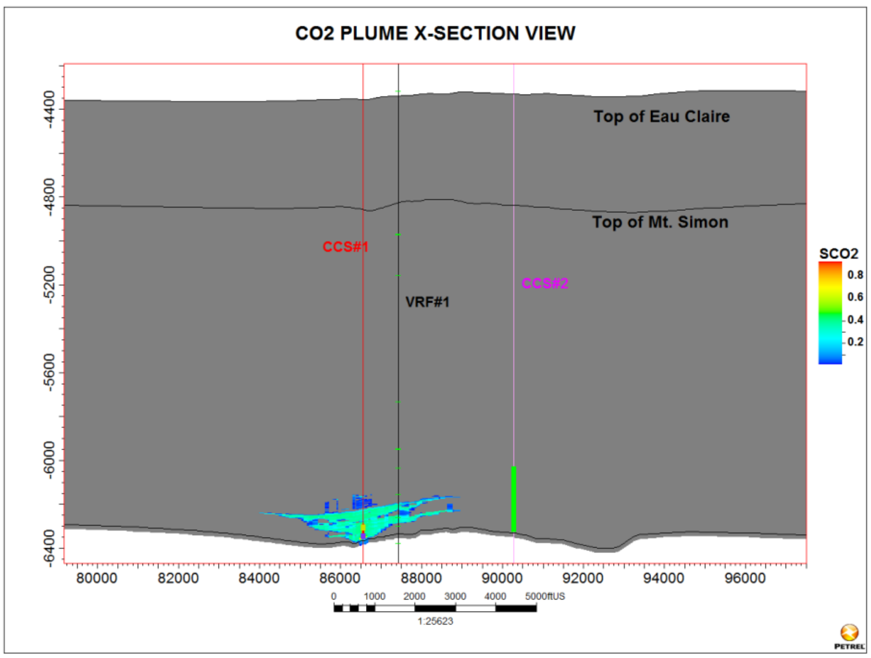
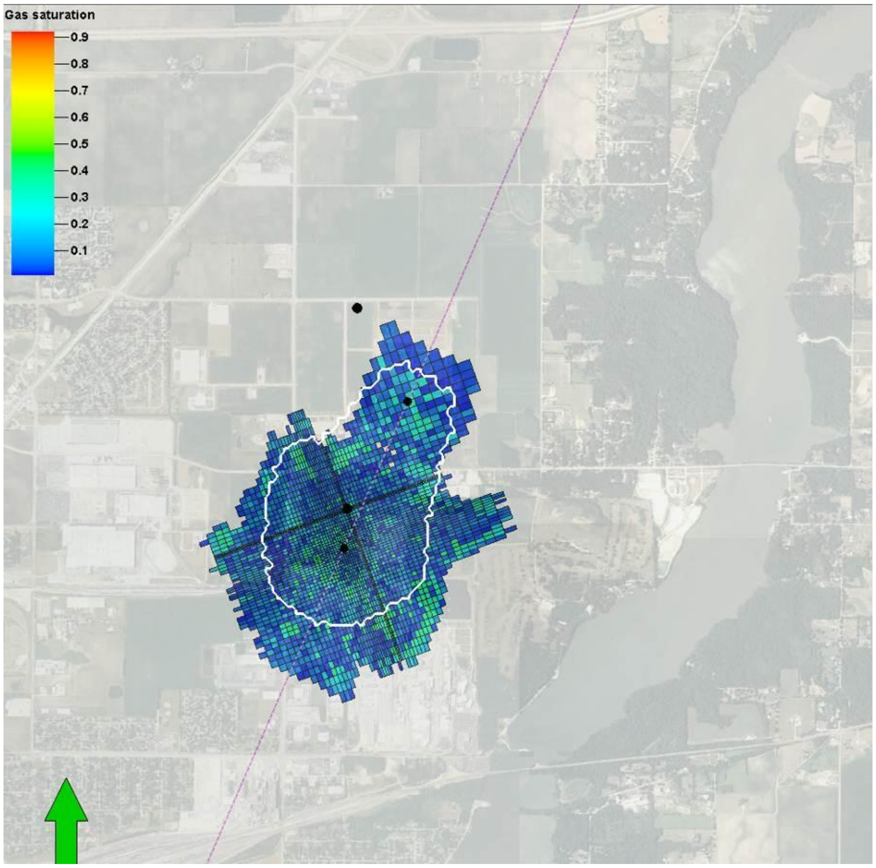


Figure 5-8: Map-view and cross section views of the predicted pressure front ($P_{i,f}$) and CO_2 plume footprints at the end of 2013 and concurrently at the start of injection into CCS#2 (Year 2).



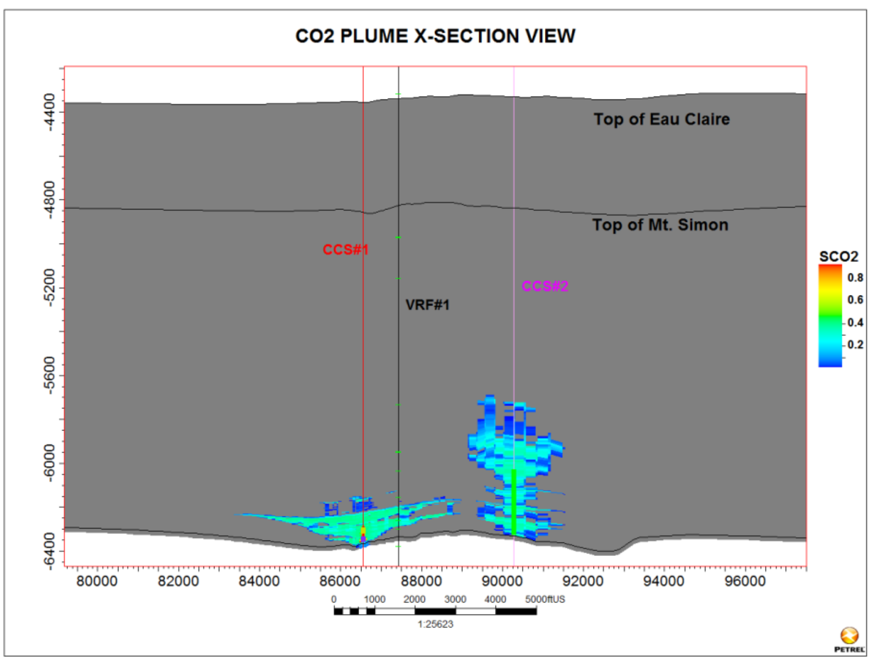


Figure 5-9: Map-view and cross section views of the predicted pressure front ($P_{i,f}$) and CO_2 plume footprints at the start of 2015 (Year 3) and concurrent with the end of injection into CCS#1.

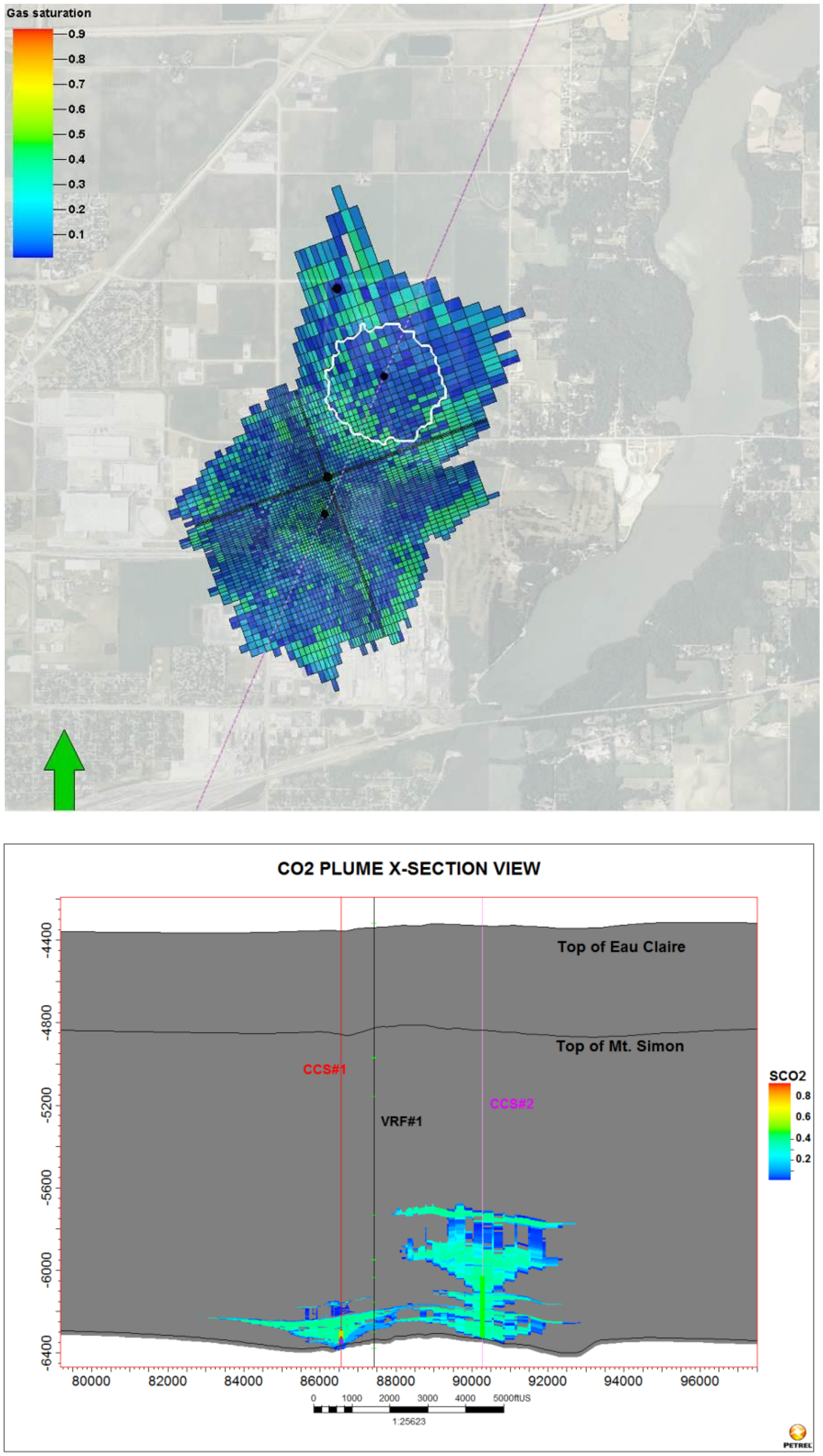
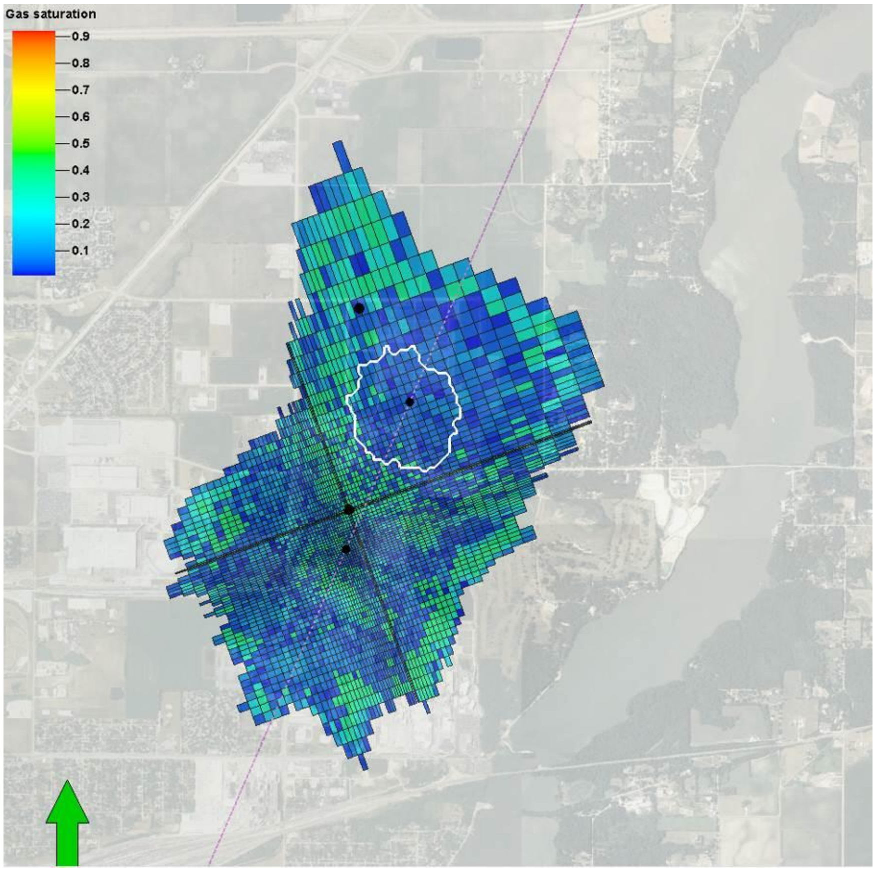


Figure 5-10: Map-view and cross section views of the predicted pressure front ($P_{i,f}$) and CO_2 plume footprints at the beginning of 2017 (Year 5).



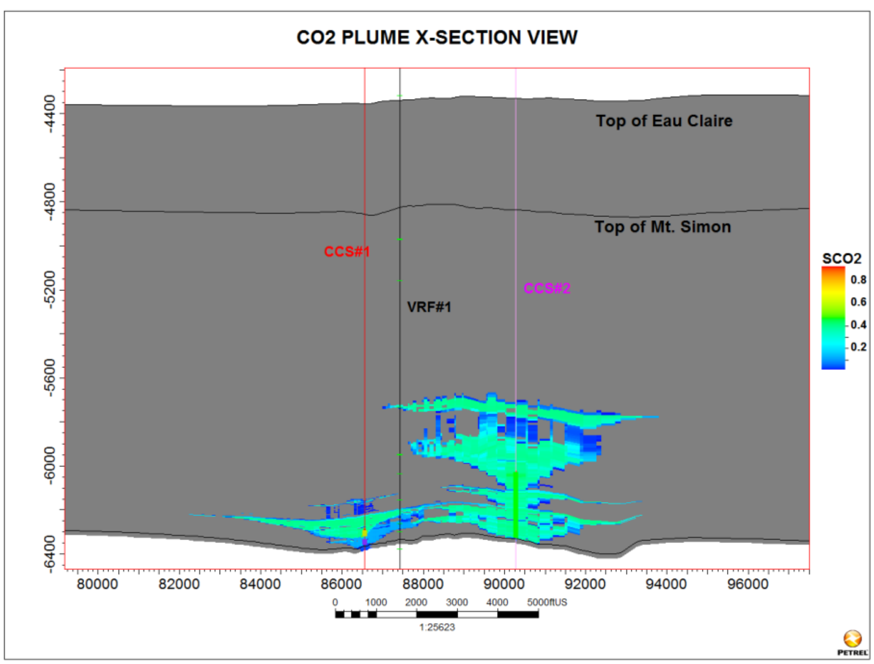


Figure 5-11: Map-view and cross section views of the predicted pressure front ($P_{i,f}$) and CO_2 plume footprints at the beginning of 2019 (Year 7) and concurrent with the ending of 5 years of injection into CCS#2.

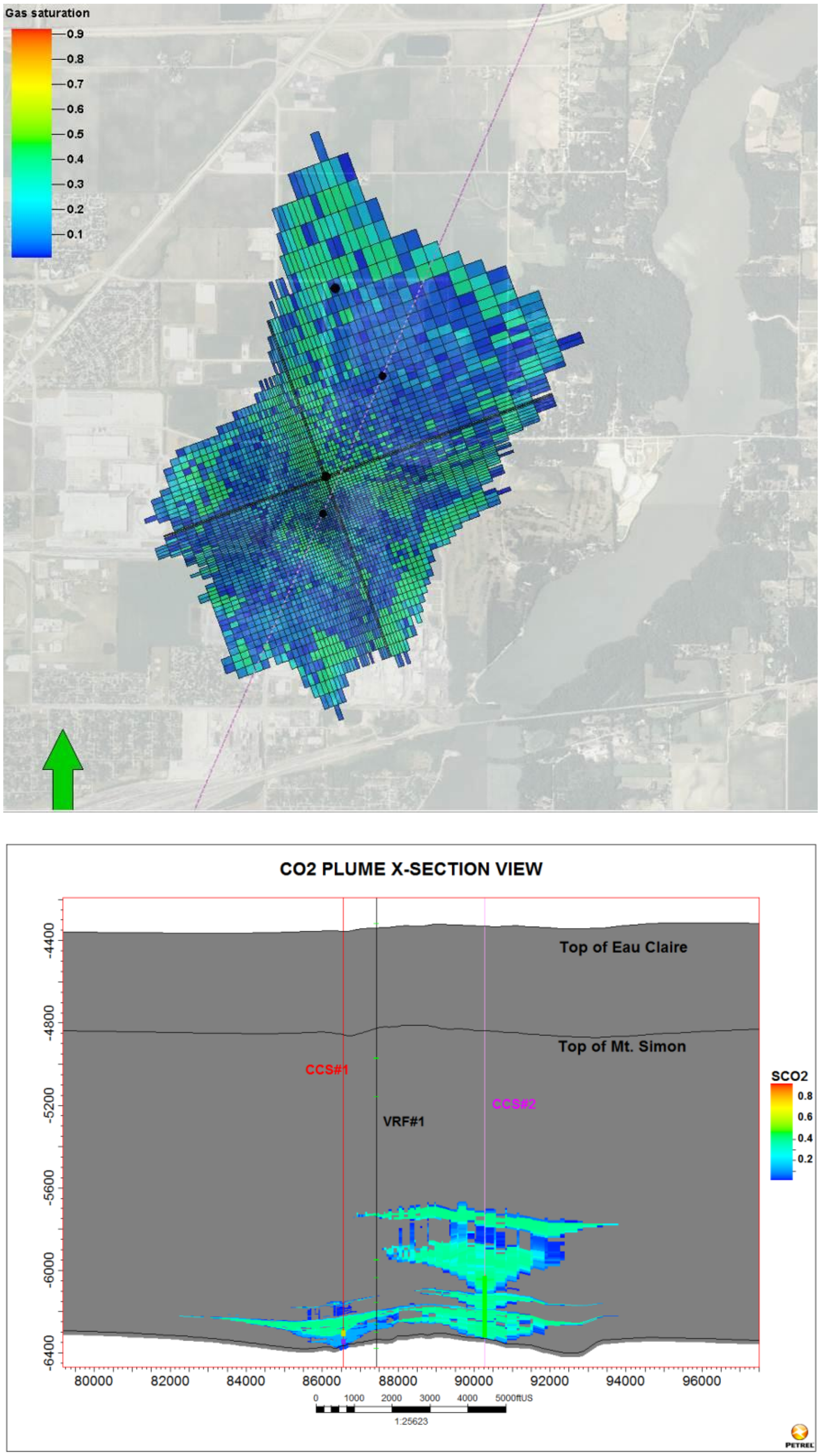


Figure 5-12: Map-view and cross section view of the predicted CO_2 plume footprint at the beginning of 2020 (Year 8). The 171 psi pressure front has completely dissipated and hence not seen in the map. Some plume growth continues however.

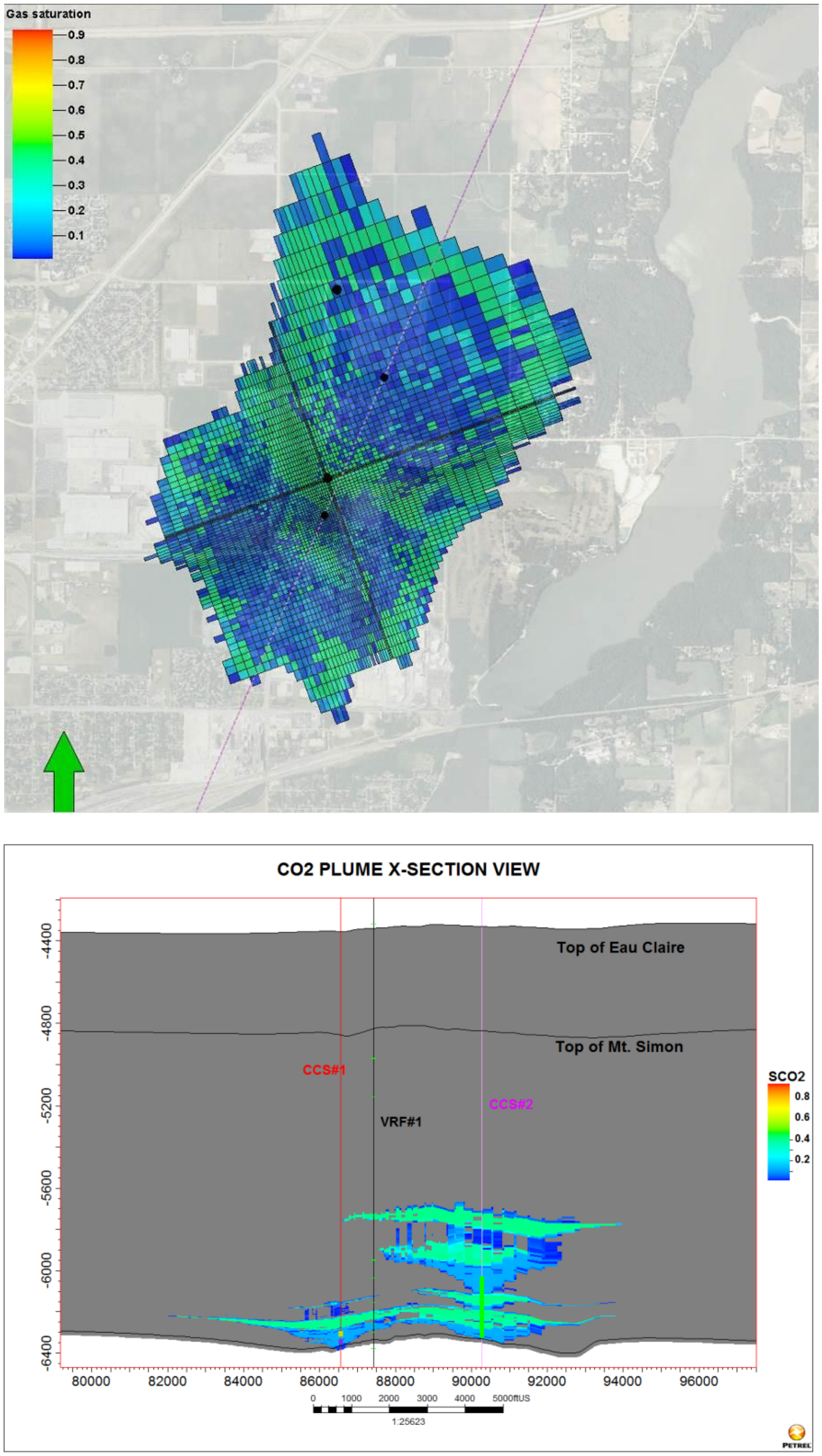


Figure 5-13: Map-view and cross section view of the predicted CO_2 plume footprint at the beginning of 2025 (Year 13).

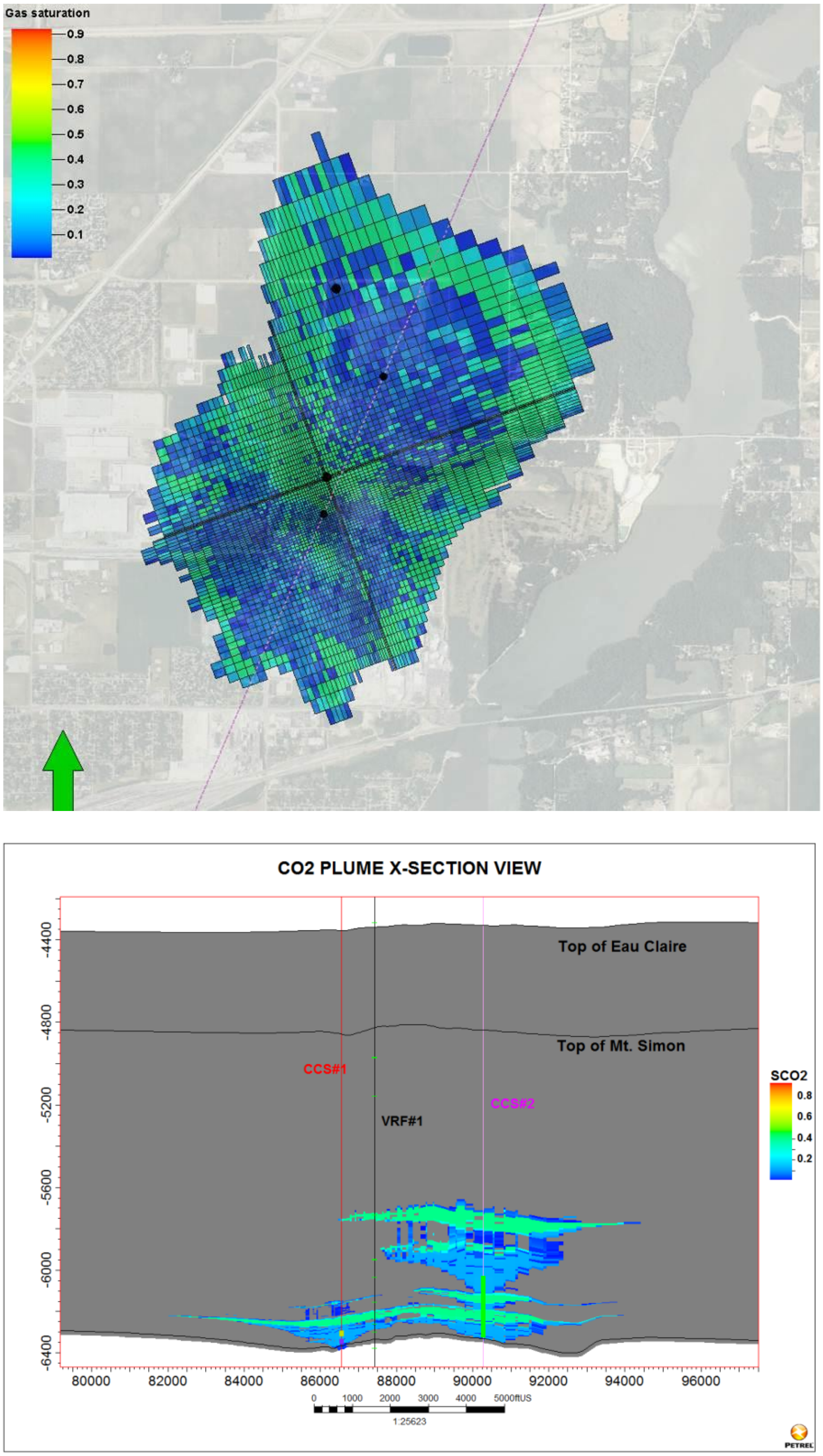


Figure 5-14: Map-view and cross section view of the predicted CO_2 plume footprint at the beginning of 2030 (Year 18).

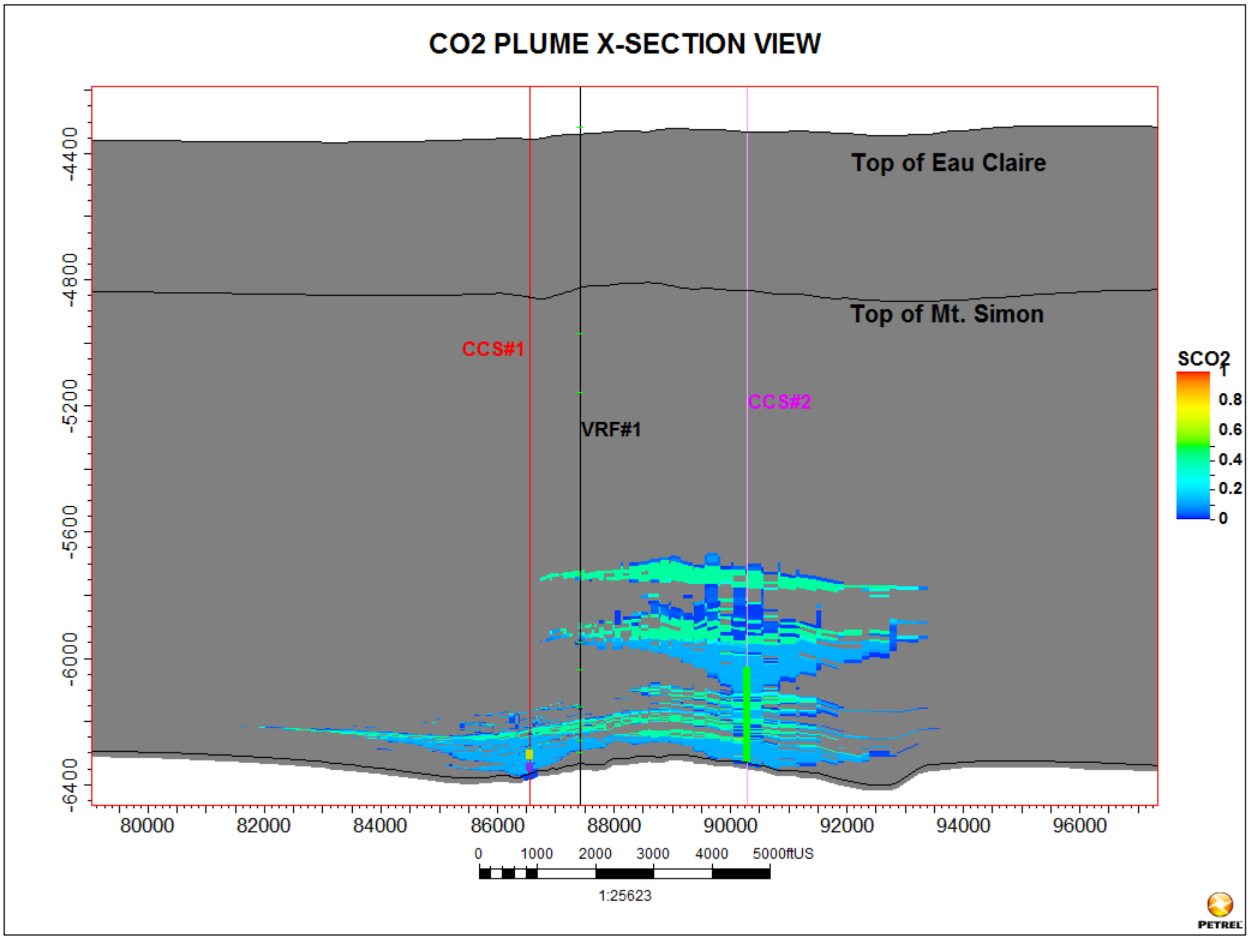


Figure 5-15: Cross section view of the predicted CO_2 plume footprint at the beginning of 2042 (Year 30).

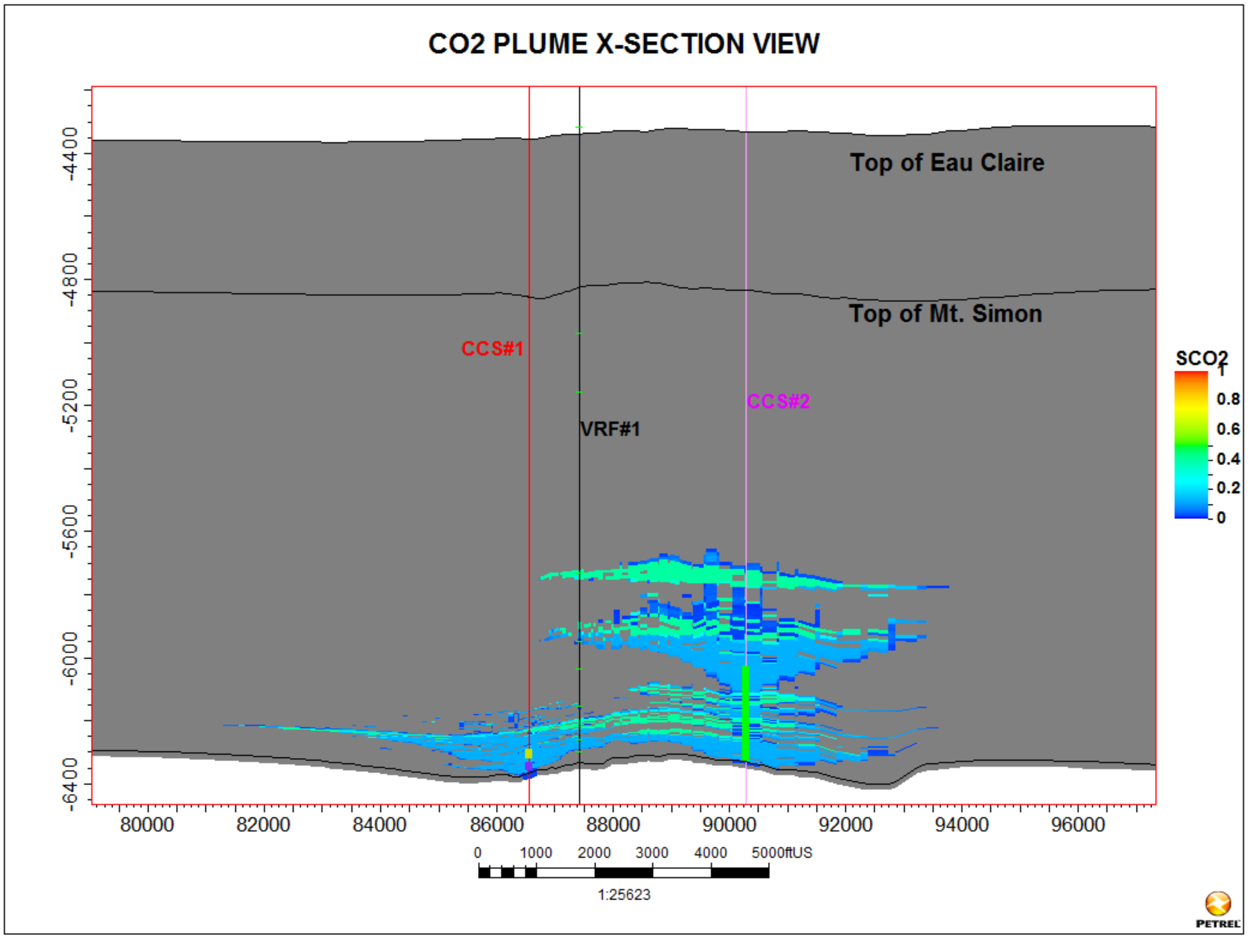


Figure 5-16: Cross section view of the predicted CO_2 plume footprint at the beginning of 2052 (Year 40).

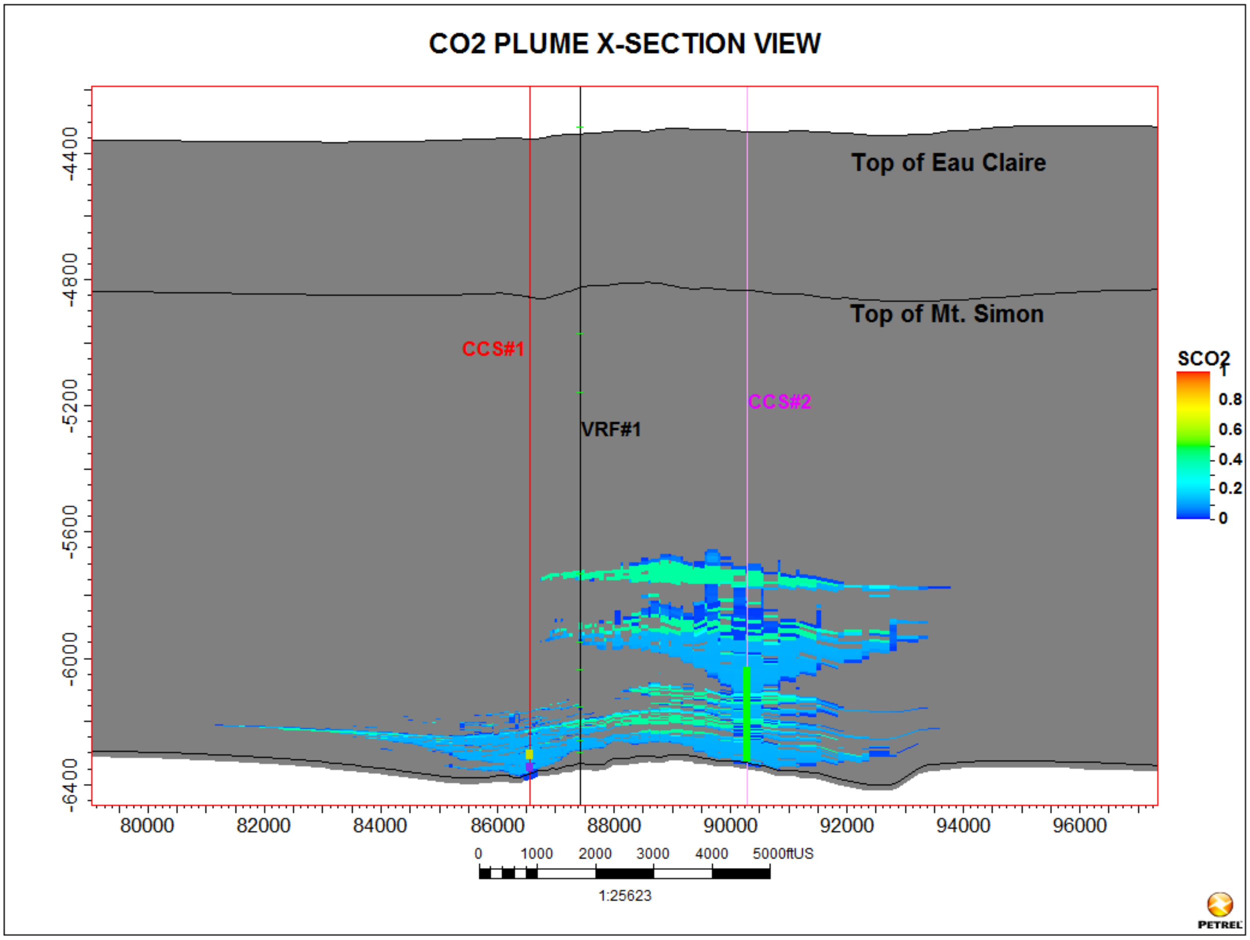


Figure 5-17: Cross section view of the predicted CO_2 plume footprint at the beginning of 2062 (Year 50).

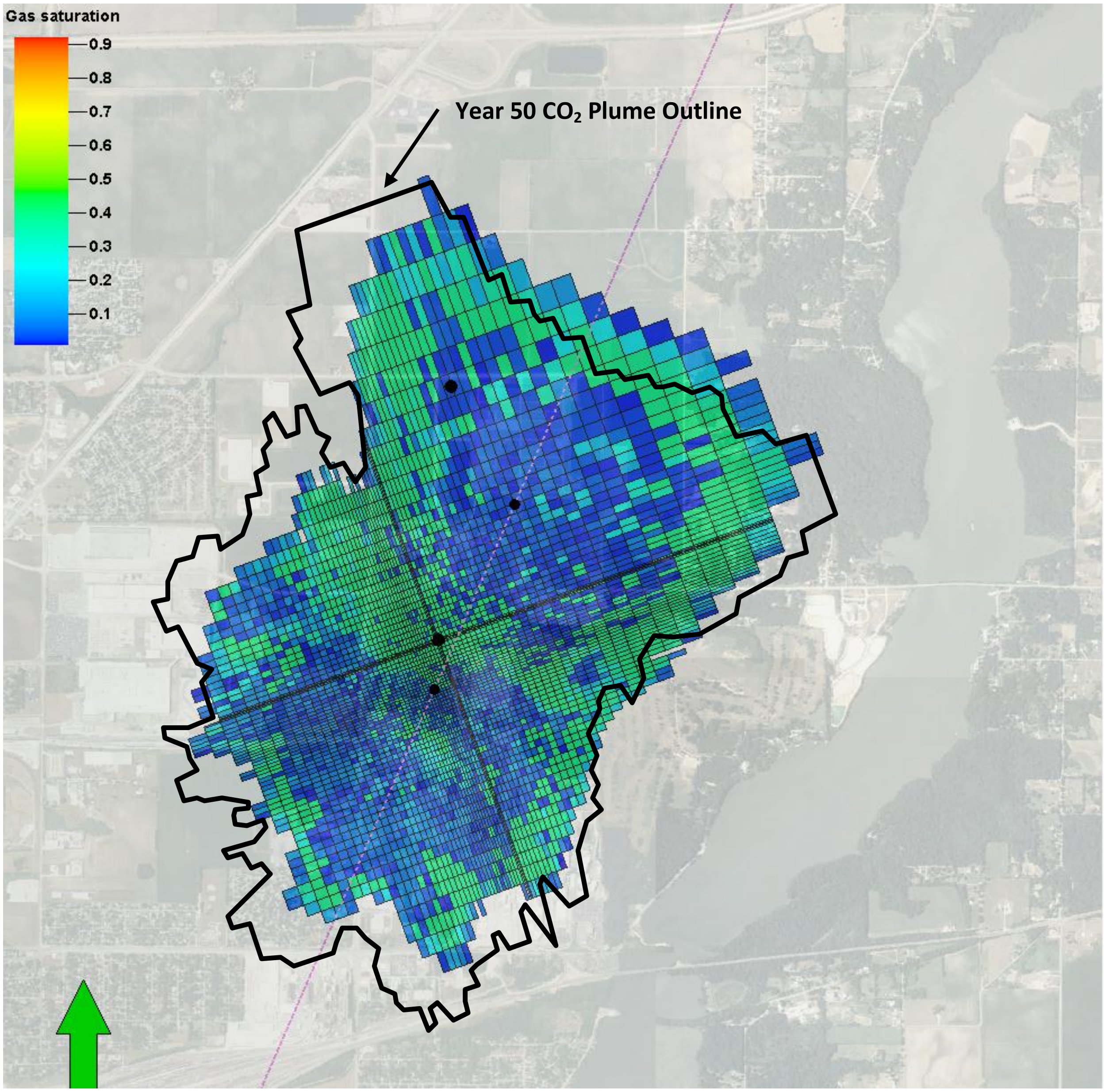


Figure 5-18: Outline of the predicted CO_2 plume footprint at the beginning of 2062 (Year 50) over of the predicted CO_2 plume footprint at the beginning of 2030 (Year 18).

Geochemical Modeling.
Geochemical modeling was used to predict the effects of injecting supercritical CO_2 into a model Mt. Simon Sandstone (Berger, Mehnert, & Roy, 2009). Based on chemical and mineralogical data from the Manlove Gas Storage Field in Illinois, the geochemical modeling software package, Geochemist's Workbench (Bethke, 2006), was used to simulate geochemical reactions. As expected, the injected CO_2 decreased the pH of the formation brine to about pH 4.5. As the reaction was allowed to progress, the pH of the formation brine increased to pH 5.4.

Berger, Mehnert, & Roy (2009) predicted that illite and glauconite dissolved initially. As the reaction was allowed to proceed, kaolinite and smectite were predicted to precipitate and that the volume of pore space would not be significantly altered (Berger, Mehnert, & Roy, 2009). Therefore, no compatibility problems, such as a major reduction in injection-formation permeability resulting from chemical precipitates, are expected.

Current model predictions indicate the CO_2 will not reach the Eau Claire seal within the 45 year post injection period. Despite this simulation result, the Geochemist's Workbench was used to model the geochemical reactions if the CO_2 comes in contact with the Eau Claire. The modeling results indicated that illite and smectite would initially dissolve, but the resulting carbonates may precipitate out of solution (Berger, Mehnert, & Roy, 2009). This dissolution and precipitation process is not expected to affect the caprock integrity.

5.5 Wells within the Area of Review

5.5.1 Tabulation of Well Data Within the AoR

The only existing wells within the AoR which currently penetrate the caprock (Eau Claire Formation) are the IBDP injection and verification wells, i.e. CCS#1 and Verification Well #1. CCS#1 was drilled in 2009. Verification Well #1 was drilled in 2010. Both wells are currently in operation for the IBDP. Well construction records have been provided to USEPA. Illinois EPA is currently the regulatory agency monitoring these well operations.

A map and cross reference table showing the location of all well penetrations within a 3.2 km (2.0 mile) radius of the ICCS site is provided in Appendix D. (Please note that a radius of 2.0 miles is larger than the AoR delineation shown in Figure 5-2 and therefore Appendix D may contain information for wells outside the new AoR.)

The latest estimate shows that a total of 447 wells are located within the vicinity. Water wells (371 of 447 wells) are the most common well type. The domestic water wells have depths of less than 60 m (200 ft). Other wells include stratigraphic test holes, non-domestic water wells, and oil and gas wells. Appendix D provides a large-scale map of the wells in the area and a listing of these wells with their API number, well owner, well location, well type, and well depth identified (if known). All wells within the 4 townships-area of the proposed injection well site were also identified (total of 3,761 wells). Information regarding these wells is provided as a supplement to this permit application (available in electronic format).

Ten oil and gas wells are located within approximately 2.4 km (1.5 miles) from the proposed injection well location. The closest well is located in the northeast quarter of Section 5, T16N, R3E. This well (API number 121150061800) was drilled as a gas well in 1933 and was 27 m (88 ft) deep. There is no record of this well being plugged. This well was likely collecting naturally occurring methane from the Quaternary sediments. The other 9 wells are located in Section 5, T16N, R3E or Section 28 and Section 29, T17N, R3E. The deepest of these oil wells is API number 121150054700, located in the northwest quarter of Section 28. This well was drilled into the Lower Devonian and was 714 m (2,344 ft) deep.

Like other areas with humid climates (Freeze and Cherry, 1979), the water table in central Illinois is expected to reflect the elevation of the land surface. Steady-state groundwater flow modeling for the IBDP site indicates that shallow groundwater flows toward the east and southeast toward the Sangamon River and Lake Decatur.

5.5.2 Number of Wells within the AoR Penetrating the Uppermost Injection Zone

With the exception of the IBDP injection and verification wells, there are no known wells within the area of review that penetrate deeper than 762 m (2,500 ft). The depth to the top of the injection zone (Mt. Simon Sandstone) is 1690 m (5,545 ft). Therefore, there are only two known wells that penetrate the uppermost injection zone.

<u>Properly Plugged and Abandoned</u>: No wells deeper than 762 m (2,500 ft) are known to have been plugged and abandoned within the AoR.

<u>Temporarily Abandoned</u>: No wells deeper than 762 m (2,500 ft) are known to have been temporarily abandoned within the AoR.

<u>Operating</u>: Two wells penetrating the uppermost injection zone (IBDP injection and verification wells, CCS #1 and Verification Well #1) are known to be in use within the AoR. The IBDP injection well began injection in November 2011.

No plugging affidavits are provided, as the IBDP wells are currently in use.

5.5.3 Proposed Corrective Action for Unplugged Wells Penetrating the Injection Zone

No wells have been found that are believed to require corrective action. The AoR will be re-evaluated periodically (see Section 5.6 below) to verify whether corrective actions may be necessary in the future.

5.6 Area of Review Re-Evaluation & Corrective Action Plan

This section is intended to satisfy the requirements of 40 CFR 146.84.

AoR Re-evaluation.
In accordance with Federal regulations for Class VI (geologic sequestration) injection wells, the AoR will be re-evaluated on a 5-year basis following issuance of the UIC permit. During each re-evaluation, the following will be performed:

- New wells within the AoR that exceed a depth of 1,500 m (4,920 ft) will be identified;
- Wells exceeding a depth of 1,500 m (4,920 ft) within the AoR that have been plugged & abandoned will be identified;
- Monitoring and operational data from the injection well (CCS#2), other surrounding wells, and other sources will be analyzed to assess whether the predicted CO_2 plume migration is consistent with actual data. An AoR Corrective Plan flowchart is shown in Figure 5-24. A table which summarizes key monitoring and operational data is shown in Table 5-2.

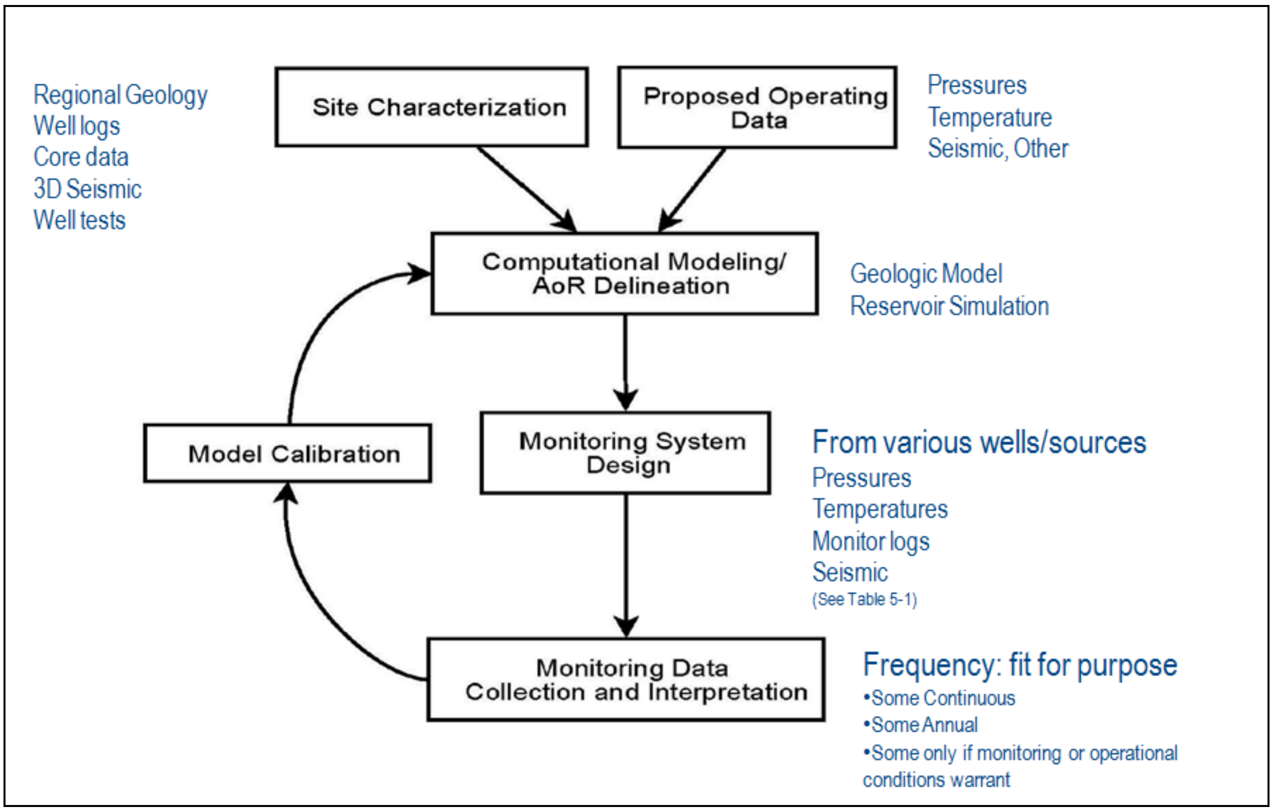


Figure 5-18: AOR Corrective Action Plan Flowchart (Reference: Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators, US EPA 2011)

	IL ICCS Wells			IBDP Wells		
	CCS #2	VW #2	GM #2	CCS#1	VW #1	GM #1
Approx. Depth (ft)	7200	7200	3500	7200	7200	3500
Approx. Distance from CCS#2 (ft)	0	2600	100	3700	2800	3800
Capable of obtaining:						
Mt. Simon pressure(s)/temperature(s)	yes	yes	no	yes	yes	no
Mt. Simon fluid sampling	no	yes	no	no	yes	no
Ironton Galesville pressure/temperature	no	no	no	no	yes	no
Ironton Galesville sampling	no	no	no	no	yes	no
St. Peter pressure/temperature	no	no	yes	no	no	no
St. Peter fluid sampling	no	no	yes	no	no	no
RST Logging (near wellbore CO_2 detection)	yes	yes	yes	yes	yes	yes
Seismic Imaging of CO_2 plume	no	no	yes	no	no	yes
Annulus Pressure at surface	yes	yes	yes	yes	yes	yes
Injection Pressure at surface	yes	no	no	yes	no	no

* Deeper formations only. Shallow USDW monitoring not included in this table

Table 5-2: Monitoring System Capability for IL-ICCS and IBDP Injection Sites.

If data are inconsistent with model predictions, ADM will assess whether the inconsistency is related to unanticipated conditions within the Mt. Simon Sandstone, heterogeneity within the injection formation, or uncertainty within the model itself. If the inconsistency suggests that location(s) within the AoR may be subject to CO_2 leakage, assessments will be made and corrective action taken.

Monitoring and operational data will be analyzed on a frequent (likely annual) basis by ADM and/or its partners in the IL-ICCS project. If data suggest that a significant change in the size or shape of the actual CO_2 plume as compared to the predicted CO_2 plume is occurring, or if the actual reservoir pressures are significantly different than predicted pressures, ADM will initiate an AoR re-evaluation, prior to the 5-year re-evaluation period.

Re-Evaluation Report.
Following each AoR re-evaluation, a report will be prepared documenting the AoR re-evaluation process, data evaluated, any corrective actions determined necessary, and the schedule for any corrective actions to be performed. The report will be submitted to the regulatory agency for approval within a timeframe specified by permit.

If no changes result from the AoR re-evaluation, the report will include the data and results demonstrating that no changes are necessary. The original AoR evaluation and all submitted re-evaluation reports shall be retained by ADM until 10 years after site closure.

Corrective Action.
If corrective actions are warranted based on the AoR re-evaluation, ADM will take the following actions:

- Identify all wells within the AoR that may require corrective action (e.g., plugging),
- Identify the appropriate corrective action for the well(s),
- Prioritize corrective actions to be performed, and
- Conduct corrective actions in an expedient manner to minimize risk of CO_2 leakage to a USDW.

Based on the information obtained for the ICCS project permit application, no corrective actions are believed to be necessary within the area of review.

State, Tribe, and Territory Contact Information.
In accordance with 40 CFR 146.82(a)(20), the State of Illinois is the only State, Tribe, or Territory identified to be within the area of review. Contact information for the State of Illinois will be directed through:

Illinois Environmental Protection Agency (IEPA)
Mr. Kevin Lesko, UIC Permit Engineer, Bureau of Land
1021 N. Grand Avenue East
Springfield, IL 62794-9276
Phone: (217) 524-3271
Kevin.Lesko@illinois.gov

5.7 References

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